

**BEFORE  
THE PUBLIC SERVICE COMMISSION OF  
SOUTH CAROLINA  
DOCKET NO. 2018-318-E**

In re: Application of Duke Energy  
Progress, LLC for Adjustments in  
Electric Rate Schedules and Tariffs and  
Request for an Accounting Order

**DIRECT TESTIMONY OF  
EZRA D. HAUSMAN, PH.D.  
FOR SIERRA CLUB  
-PUBLIC VERSION-**

1     **I.     PROFESSIONAL QUALIFICATIONS AND PURPOSE OF TESTIMONY**

2     **Q.     Please state your name, occupation, and business address.**

3     A.     My name is Ezra D. Hausman, Ph.D. I am an independent consultant doing business as  
4           Ezra Hausman Consulting, operating from offices at 77 Kaposia Street, Auburndale,  
5           Massachusetts 02466.

6     **Q.     Are you providing any exhibits with your testimony?**

7     A.     Yes. I am sponsoring the following exhibits:

Exhibit No.	Marked Confidential by DEP	Description
1	No	Resume of Ezra D. Hausman, Ph.D.
2	Yes	Response to Sierra Club Data Request 1-2(d)
3	Yes	Response to Sierra Club Data Request 1-2(c), attachment 1
4	Yes	Response to Sierra Club Data Request 1-2(c), attachment 2
5	No	Response to Sierra Club Data Request 1-4
6	Yes	Response to Sierra Club Data Request 2-1
7	Yes	Response to Sierra Club Data Request 2-2
8	No	Response to Sierra Club Data Request 1-6
9	No	Response to Sierra Club Data Request 1-8
10	Yes	Response to Sierra Club Data Request 1-17
11	No	Response to Sierra Club Data Request 1-3
12	Yes	Response to Sierra Club Data Request 1-19, attachment 1
13	Yes	Response to Sierra Club Data Request 1-19, attachment 2
14	Yes	Response to Sierra Club Data Request 1-14

8

1     **Q.     What is your educational and professional background?**

2     A.     I hold a BA in Psychology from Wesleyan University, an MS in Environmental  
3           Engineering from Tufts University, an SM in Applied Physics from Harvard University,  
4           and a Ph.D. in Atmospheric Chemistry from Harvard University. I have been involved in  
5           analysis of both regulated and restructured electricity markets for over 20 years.  
  
6           I have worked as an independent consultant and expert based on my expertise and  
7           experience in energy economics and environmental science since 2014. From 2005 until  
8           early 2014, I was employed at Synapse Energy Economics, Inc., a research and  
9           consulting company located in Cambridge, Massachusetts, where I served most recently  
10          as Vice President and Chief Operating Officer. At Synapse, and continuing as an  
11          independent consultant, I have provided expert consulting services in areas including:  
12          state and regional energy, capacity, and transmission planning, including both utility  
13          resource planning and long-term (multi-decadal) climate-constrained resource planning;  
14          regulatory and ratemaking proceedings; electricity and generating capacity market design  
15          and analysis; energy efficiency programs; electric system dispatch modeling; economic  
16          analysis of environmental and other regulations, including greenhouse gas regulation, in  
17          electricity markets; economic analysis, price forecasting, and asset valuation in electricity  
18          markets; quantification of the economic and environmental benefits of displaced  
19          emissions; treatment of energy efficiency and renewable energy in electricity and  
20          capacity markets; and regulation and mitigation of greenhouse gas emissions from the  
21          supply and demand sides of the U.S. electricity sector.  
  
22          Prior to joining Synapse, I was employed from 1998 through 2004 as a Senior Associate  
23          at Tabors Caramanis and Associates (TCA) of Cambridge, Massachusetts. In 2004, TCA

1 was acquired by Charles River Associates (CRA), where I remained until I joined  
2 Synapse in 2005. At TCA/CRA, I performed a wide range of electricity market and  
3 economic analyses and price forecast modeling studies. These included asset valuation  
4 studies, market transition cost/benefit studies, market power analyses, and litigation  
5 support. I have extensive personal experience with market simulation, production cost  
6 modeling, and resource planning methodologies and software.

7 I have provided testimony and/or appeared before public utility commissions or  
8 legislative committees in Arizona, Florida, Illinois, Idaho, Iowa, Kansas, Louisiana,  
9 Maryland, Massachusetts, Minnesota, Mississippi, Missouri, North Carolina, New  
10 Hampshire, New Jersey, Nevada, South Dakota, Vermont, Virginia, and Washington  
11 State, as well as at the federal level. My clients have included numerous State agencies,  
12 the federal Department of Justice and the Environmental Protection agency, non-  
13 governmental organizations, industry associations, resource developers, and others. I  
14 have provided expert representation for stakeholders at the PJM ISO, the California ISO,  
15 the Midwest ISO, and at the FERC.

16 I have provided a detailed resume as Exhibit 1.

17 **Q. Have you previously testified before the South Carolina Public Service**  
18 **Commission?**

19 A. Yes. I submitted prefiled testimony regarding Duke Energy Carolinas' application for  
20 adjustments in electric rate schedules and tariffs and request for an accounting order  
21 (docket no. 2018-319-E).

22 **Q. What is the purpose of your testimony in this proceeding?**

23 A. In this proceeding, Duke Energy Progress ("DEP" or "Company") is requesting a net

1 base increase in its retail revenues that includes, among other things, costs related to the  
2 combustion of coal at DEP's retired and operating electric generating units. These costs  
3 include a \$100 million investment for conversion to a dry bottom ash handling system at  
4 DEP's Roxboro Station (Application at 9) and additional costs totaling approximately  
5 \$13 million for the closure of DEP's coal ash basins across the Carolinas. (Application at  
6 11.) In my testimony, I review the costs and risks associated with continued operation of  
7 DEP's Mayo and Roxboro plants and caution against the continued investment in coal  
8 units that are likely to be uneconomic for customers.

9 **Q. What are your recommendations for the Commission in this proceeding?**

10 A. I recommend that the Commission reject DEP's request to recover its \$100 million  
11 investment in retrofits at the Roxboro plant because DEP has not demonstrated that such  
12 investment was economically preferable to the early retirement of that plant, when  
13 retirement would have allowed ratepayers to avoid both that investment and future capital  
14 costs for the plant.

15 In addition, I recommend that the South Carolina Public Service Commission  
16 ("Commission") require DEP to complete a comprehensive economic and retirement  
17 analysis of each of its coal units. This analysis should identify and quantify the total costs  
18 of managing past and future coal combustion residuals ("CCR", also referred to generally  
19 as "ash") as well as the costs of all future capital investments necessary to continue  
20 operating the plants, including additional investments to manage coal ash and other  
21 environmental compliance requirements. This comprehensive analysis should include full  
22 consideration of non-fossil-generation alternatives for meeting customer requirements,  
23 including transmission enhancements, renewable energy sources, energy efficiency, and  
24 storage. If the Commission otherwise concludes that DEP's request for recovery of coal

ash remediation and cleanup costs in this proceeding to be reasonable and prudent, the Commission should condition its approval on its review of the Company's filing this comprehensive analysis for Commission review. This will allow the Commission to consider whether DEP's coal ash remediation investments provide commensurate benefits to ratepayers in the full context of the past and future operations of DEP's coal units.

Once the costs, benefits, and customer risks associated with continued operation versus early retirement of the plants are fully evaluated, the Commission will be better positioned to assess the reasonableness and prudence of any proposed additional capital investments. Moreover, such evaluation will allow the Company to better plan for transitioning to a cleaner energy mix, while minimizing the impact on ratepayers.

## II. Costs Associated with Coal Combustion

**Q. In the current proceeding, is DEP seeking recovery of capital investments at its coal units?**

**A.** Yes. DEP is seeking recovery of approximately \$100 million in capital additions made at Roxboro to convert the plant to a dry bottom ash handling system. (Application at 9; Miller Direct at 7.)

**Q. Did DEP analyze the option of retiring the Roxboro plant as an alternative to installation of the dry bottom ash handling system?**

**A.** [CONFIDENTIAL] [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

1 [REDACTED]  
2 [REDACTED]  
3 [REDACTED]  
4 [REDACTED]  
5 [REDACTED]  
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 6 [REDACTED]  
 7 [REDACTED]  
 8 [REDACTED]  
 9 [REDACTED]  
 10 [REDACTED] [CONFIDENTIAL]

11 **Q. Does DEP plan to make additional capital investments at its Roxboro and Mayo**  
 12 **plants?**

13 A. Yes. Mr. Kerin states that “the Company is adding dry fly ash, bottom ash, and FGD  
 14 blowdown handling systems to operating coal-fired plants that are not already so  
 15 equipped.” (Kerin Direct at 8, lines 17-19.) It is not clear from this statement the degree  
 16 to which these investments are included in the current rate request, or are part of the  
 17 request for deferred accounting, or in general how the Company plans to recover costs for  
 18 these projects. However, the ratepayer funds involved would seem to merit more than this  
 19 cursory description.

20 As provided in response to Sierra Club data requests (and as shown in Table 1, below) as  
 21 of January 31, 2019 DEP had spent over \$19 million on dry CCR management upgrades  
 22 at Mayo, and over \$242 million at Roxboro. While CCR related, these capital  
 23 investments that were made not to remediate the ash ponds, but to keep the coal plants

running under the updated ash handling mandates.

*Table 1. Capital investment in DEP plants for dry CCR management as of January 31, 2019*

Site	Dry Fly Ash*	Dry Bottom Ash**	FGD Blowdown***
<b>Mayo</b>	\$ 5,010,948		\$ 14,064,534
<b>Roxboro</b>	\$ 36,961,257	\$ 97,759,981	\$ 107,371,902

\* Response to Sierra Club Data Request 1-4 (Exhibit 5)

\*\* Response to Sierra Club Data Request 1-6 (Exhibit 8)

\*\*\* Response to Sierra Club Data Request 1-8 (Exhibit 9)

In addition to CCR-related costs, “DE Progress plans to invest approximately \$730 million in its Fossil/Hydro/Solar fleet during the period 2019 - 2021. (Miller Direct at 13, lines 5-7.) [CONFIDENTIAL] [REDACTED]

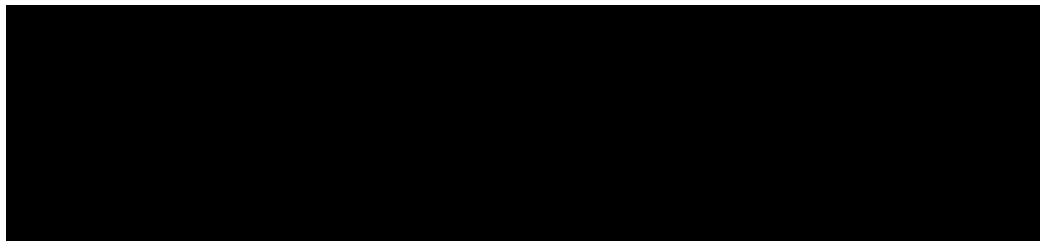
[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED] [CONFIDENTIAL] The Company should be put on notice that large capital investments will not be approved for recovery from ratepayers in the future unless and until they are shown to be in ratepayers’ interests through a comprehensive retirement analysis, with a full evaluation of alternatives.

1 [CONFIDENTIAL] *Table 2. Recent and Planned Capital Expenditures at DEP Coal Plants*



2  
3  
4  
5 **Q. Has DEP performed a retirement analysis that compares the accelerated retirement**  
6 **of one or more Roxboro units, and the potential resulting avoidance of the capital**  
7 **expenditures necessary to continue operating the units?**

8 A. No. [CONFIDENTIAL] [REDACTED]  
9 [REDACTED]  
10 [REDACTED]  
11 [REDACTED]  
12 [REDACTED]  
13 [REDACTED]  
14 [REDACTED]  
15 [REDACTED]  
16 [REDACTED] [CONFIDENTIAL]

17 **Q. Has DEP performed an adequate retirement analysis for its Mayo coal plant?**

18 A. No. [CONFIDENTIAL] [REDACTED]  
19 [REDACTED]  
20 [REDACTED]  
21 [REDACTED]  
22 [REDACTED]  
23 [REDACTED]

1 [REDACTED]  
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13 [REDACTED]  
14 [REDACTED]  
15 [REDACTED]  
16 [REDACTED]  
17 [REDACTED] [CONFIDENTIAL]  
18 **Q. Has DEP adequately justified its decision to continue running all of its coal units**  
19 **until the probable retirement dates identified in the 2016 depreciation study?**  
20 **A. [CONFIDENTIAL] [REDACTED]**  
21 [REDACTED]  
22 [REDACTED]  
23 [REDACTED]

1 [REDACTED]  
 2 [REDACTED]  
 3 [REDACTED]  
 4 [REDACTED]  
 5 [REDACTED]  
 6 [REDACTED]  
 7 [REDACTED]  
 8 [REDACTED]  
 9 [REDACTED]  
 10 [REDACTED]  
 11 [REDACTED]  
 12 [REDACTED] [CONFIDENTIAL]

13 **Q. Is DEP seeking recovery of any other costs related to its coal units?**

14 A. Yes. DEP is also seeking recovery of coal ash basin closure costs incurred from July 1,  
 15 2016 through December 31, 2018. According to DEP witness Laura Bateman, “The total  
 16 system spend on coal ash basin closure costs during this period...for DE Progress is  
 17 \$526.4 million.” (Bateman Direct at 21, lines 15-17.) After allocating between  
 18 jurisdictions and making certain adjustments, Ms. Bateman concludes that the  
 19 Company’s total deferred balance for South Carolina is \$50.4 million which, when added  
 20 to the Company’s requested return, leads to a requested annual amortization expense for  
 21 deferred CCR compliance of \$12.9 million. (Bateman Direct at 22, lines 5-11.)

22 **Q. Are there additional costs that DEP expects to incur in the future related to cleanup  
 23 and remediation of its CCR wastes?**

24 A. Yes. DEP “expects to continue to invest significant amounts related to CCR

1 environmental compliance after the December 2018 cut-off in this case” and, thus, is  
 2 requesting approval “to defer CCR compliance spend related to ash basin closure  
 3 beginning January 1, 2019, the depreciation and return on CCR compliance investments  
 4 related to continued plant operations placed in service on or after January 1, 2019, and a  
 5 return on both deferred balances at the overall rate of return approved in this case.”  
 6 (Application at 11-12.)

7 **Q. Were these costs included in DEP’s application?**

8 A. No. DEP has not identified the anticipated total cost of closure of its ash basins. Instead,  
 9 “the Company is requesting the Commission approve a continuation of the deferral of  
 10 CCR compliance-related costs, similar to what it approved in the 2016 Rate Case, for  
 11 costs not included in this case. Specifically, the Company is requesting approval to defer  
 12 coal CCR compliance spend related to ash basin closure beginning January 1, 2019, the  
 13 depreciation and return on CCR compliance investments related to continued plant  
 14 operations placed in service on or after January 1, 2019, and a return on both deferred  
 15 balances at the overall rate of return approved in this case.” (Application at 12.)

16 **Q. Should the Commission be concerned that DEP is not identifying these future**  
 17 **cleanup costs in the current case?**

18 A. Yes. Based on filings by the Company to the North Carolina Utilities Commission,  
 19 closure costs could total more than two billion dollars over forty years.<sup>1</sup> The Commission  
 20 can expect to see these costs in future rate cases or rider applications, despite the fact that

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<sup>1</sup> In re Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges, Before the North Carolina Utilities Commission, Docket No. E-2, sub 1142, Direct Testimony of Jon F. Kerin, Exhibit 11 (July 1, 2017), *available at* <https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=2e602d93-a288-4a6f-8c7c-d8684a747d91>.

1 these costs arise from long-ago combustion at coal plants that provides no benefit to  
2 current and future ratepayers—in fact many or all of these coal plants will be long closed  
3 by the time the cleanup is complete. Costs that are likely to affect ratepayers for decades  
4 to come should not be hidden in a piecemeal series of rate requests without a full analysis  
5 and disclosure to the Commission—only by identifying the total cost now can the  
6 reasonableness of the Company’s request adequately be evaluated. The Commission  
7 should insist on a comprehensive retirement study that compares the full suite of future  
8 environmental and coal ash costs and closure options to the option of accelerating the  
9 retirement of the plants and avoiding these costs to the extent possible.

10 **Q. Are the full costs of managing DEP’s existing and future ash wastes and**  
11 **impoundments known at this time?**

12 A. No. The closure of coal ash basins and cleanup groundwater contamination, which  
13 involve such complicated variables as underground soil properties and groundwater flow,  
14 are subject to even greater uncertainties. Further, the Company’s assertion that cap-in-  
15 place at the Mayo and Roxboro impoundments will adequately achieve long-term  
16 protection of and cessation of discharges to ground and surface waters is uncertain. The  
17 North Carolina Department of Environmental Quality has yet to approve DEP’s basin  
18 closure plans. In both South Carolina and Virginia, utilities have been required to  
19 excavate their coal ash basins. Thus, excavation could ultimately be required for DEP’s  
20 ash basins, at significantly greater cost, in order to fully protect groundwater and surface  
21 water.

22 **Q. Please briefly describe the kind of comprehensive retirement analysis you**  
23 **recommend.**

24 A. DEP should be directed to perform a comprehensive retirement analysis of its coal plants,

1 considering a range of future market conditions, such as fuel costs, emissions costs, and  
 2 regulatory drivers. The analysis should take into account uncertainty in future operating  
 3 and CCR management costs. It should consider partial shutdown options as well as full  
 4 plant retirements. Importantly, the analysis should include consideration of a full range of  
 5 alternatives for meeting customer needs in the absence of each coal unit, including  
 6 demand management, transmission, renewables, and storage, to determine the extent to  
 7 which future costs and risks can be reduced by early retirement of any or all of the units  
 8 at the Company's coal plants in favor of non-fossil energy solutions.

9 **Q. Can you provide examples of other utilities that have performed retirement analyses**  
 10 **that considered other, non-gas options for replacing coal generation, and if so,**  
 11 **please briefly describe the outcomes.**

12 A. Yes. One example can be found in the Northern Indiana Power Supply Company's  
 13 ("NIPSCO") 2018 IRP, for which the Company's capacity expansion modeling showed  
 14 that retiring all of its coal units early was the lowest-cost option for ratepayers. Under its  
 15 "preferred plan", NIPSCO proposed to accelerate the retirement of 85% of its coal  
 16 capacity by the end of 2023 and 100% by the end of 2028, and "[r]eplace retired coal  
 17 generation resources with lower cost renewables including wind, solar and battery  
 18 storage."<sup>2</sup>

19 As another example, the Michigan Public Service Commission directed Consumers  
 20 Energy in its 2017 utility rate case to file a retirement study for a number of its coal units

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<sup>2</sup> Northern Indiana Public Service Company LLC, 2018 Integrated Resource Plan 3 (Oct. 31, 2018), available at <https://www.nipsco.com/docs/default-source/default-document-library/2018-nipsco-irp.pdf>.

1 as part of its upcoming IRP, and to do so expeditiously while certain capital costs at these  
 2 units could still be avoided.<sup>3</sup> When Consumers did this analysis, it concluded that retiring  
 3 two of its four coal units in 2023 (instead of 2031, the end of their design lives) was the  
 4 preferable course option for ratepayers, especially when the uncertainty over future costs  
 5 was considered.<sup>4</sup> According to Consumers witness Thomas P. Clark, the Company's  
 6 "Preferred Course of Action" ("PCA") "includes increasing [energy waste reduction]  
 7 from current levels to 2.25%, ramping DR resources to 1,250 MW, implementing  
 8 Conservation Voltage Reduction ("CVR") with the enablement of the Company's Grid  
 9 Modernization initiative, and constructing up to 5,000 MW of new solar generation  
 10 resources by 2031. Additional solar and battery storage is planned to meet load growth  
 11 and backfill plant retirements throughout the 2030's resulting in 450 MW of battery  
 12 storage and an incremental 1,350 MW of solar."<sup>5</sup> Mr. Clark further stressed that "The  
 13 PCA does not incorporate a new NGCT nor NGCC to meet any of the Company's  
 14 projected capacity needs. The PCA includes incremental levels of demand-side  
 15 management and renewable generation."<sup>6</sup>

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<sup>3</sup> In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief; Case No. U-18322, March 29, 2018 Order, available at <https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000002283XAAQ>.

<sup>4</sup> In re the application of Consumers Energy Company for approval of its integrated resource plan, before the Michigan Public Service Commission, Case No. U-20165, Application at 2, 8-9, 32 (June 15, 2018), available at <https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000231usAAA>.

<sup>5</sup> In re the application of Consumers Energy Company for approval of its integrated resource plan, before the Michigan Public Service Commission, Case No. U-20165, Direct Testimony of Thomas P. Clark, 6-7 (June 15, 2018) available at <https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000231usAAA>.

<sup>6</sup> Ibid, page 64.

1     III.     Remaining Life of the Mayo and Roxboro Coal Plants

2     **Q.     What are the expected retirement dates of DEP's Mayo and Roxboro plants?**

3     A.     As shown in the direct testimony of DEP witness David L. Doss, Jr., Exhibit 2 (2016  
4           Depreciation Study), the Mayo plant has a "Probable Retirement Year" of 2035, Roxboro  
5           Units 1 and 2 of 2028, and Roxboro Units 3 and 4 of 2033. By those dates, the Mayo  
6           plant will have been in service for 52 years and the Roxboro units for between 53 and 62  
7           years.

8     **Q.     What was the basis of DEP's projected end-of-life dates?**

9     A.     As described on page III-5 of the 2016 Depreciation Study (Doss Exhibit 2), "The  
10          depreciable life span estimates for power generating stations were the result of  
11          considering experienced life spans of similar generating units, the age of surviving units,  
12          general operating characteristics of the units, major refurbishments, discussions with  
13          management personnel concerning the probable long-term outlook for the units, and the  
14          estimate of the operating partner, if applicable...the depreciable life span estimate for  
15          most steam, base-load units is 52 to 63 years, which is within the typical range of life  
16          spans for such units."

17    **Q.     Are the Company's projected retirement dates for Mayo and Roxboro reasonable**  
18          **given the changes in industry outlook over the last several years?**

19    A.     No. These lifetime projections cannot be reconciled with current industry conditions and  
20          trends. Absent a unit-specific analysis, I find that the projected lifespans for Mayo and  
21          Roxboro do not comport with the challenges facing coal plants or with the likely future  
22          operations at DEP's coal plants. In fact, the economic and regulatory environment for  
23          coal plants today is manifestly different from the conditions in 2008 or 2011.

1     **Q.     Please explain.**

2     A.     Throughout the 20th century and into the first decade of the 21st, there were very few  
3           retirements of coal plants, as demand for power grew and the availability and the  
4           relatively low cost of coal made it more attractive to utilities than alternative energy  
5           sources. In addition, the environmental and public health impacts of coal combustion  
6           were less well-known than they are today (or were considered an acceptable cost of this  
7           engine of economic growth). In 1970, the US Congress passed the Clean Air Act and  
8           began the process of requiring coal plants to install pollution controls to reduce the  
9           environmental and health impacts of their emissions. However, Congress exempted many  
10          existing coal plants from strict emissions control requirements. This loophole had the  
11          unintended consequence of actually prolonging the life of many coal plants that lacked  
12          modern pollution controls, as companies sought to avoid the costs associated with the  
13          technology that would be required on new, or substantially refurbished, coal-fired power  
14          plants.

15          Since around the time of DEP's last depreciation study in 2011, however, the rate of coal  
16          plant retirements or conversions has increased dramatically. In much of the country, the  
17          growth in demand for electricity has slowed or even halted due to factors such as  
18          stringent appliance energy efficiency standards, along with utility-run energy efficiency  
19          programs. More recent environmental regulations have required existing coal-fired plants  
20          to reduce their emissions of harmful and haze-inducing pollutants, in addition to better  
21          management of their water use, their impact on aquatic life, and disposal of coal  
22          combustion residuals. These mandates can necessitate capital investments in equipment  
23          upgrades in order for plants to continue operating.

1 At the same time, the cost of renewable energy sources has plummeted, while the demand  
2 for renewable-sourced energy has increased, both because of the sharply decreasing costs  
3 of renewable energy and as a result of state Renewable Portfolio Standards and other  
4 state and federal policies. The US Department of Energy's Annual Energy Outlook  
5 (AEO) for 2019 projects an increase in U.S. renewable generation of 59% over 2017  
6 levels by 2035, compared to a *decrease* in output for coal generation of 22%. As the  
7 capability of battery storage increases and the cost declines, the pairing of solar energy  
8 and battery storage systems makes high penetrations of solar energy to meet both energy  
9 and capacity needs increasingly feasible.<sup>7</sup>

10 Finally, coal-fired plants are very large emitters of carbon dioxide (CO<sub>2</sub>) and other  
11 greenhouse gases, which have well-documented and extremely harmful long-term  
12 impacts on the Earth's climate and environment, human health, and economic well-being.  
13 The United States currently lags other countries in federal policies to address this threat.  
14 However, numerous states—for example, the members of the Regional Greenhouse Gas  
15 Initiative (RGGI) in the Northeast—are moving aggressively to reduce the greenhouse  
16 gas emissions associated with electricity production, and are transforming the regional  
17 electricity market by pushing the generation mix away from high-carbon sources and  
18 towards cleaner generating technologies. On October 29, 2018, the North Carolina  
19 Governor signed an Executive Order setting a statewide goal of reducing greenhouse gas

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<sup>7</sup> See, for example, "Solar+Storage: Reducing Barriers through Cost-optimization and Market Characterization, a joint endeavor of Clean Energy Group and the National Renewable Energy Laboratory (NREL)" and other related reports at <https://www.cleaneenergygroup.org/ceg-projects/solar-storage-optimization/>.

1 emission to forty percent below 2005 levels by 2025.<sup>8</sup> There has also been widespread  
 2 recognition throughout the electric industry that the United States will ultimately  
 3 implement policies that impose a price on greenhouse gas emissions, as the deleterious  
 4 effects of global climate change become increasingly difficult to ignore or deny.

5 These factors have led to conditions where many coal plants cannot compete  
 6 economically, and even more cannot justify continued investments in either  
 7 environmental upgrades or other significant capital improvements given their long-term  
 8 outlook. As a result, coal plants have been retired, or repowered to burn gas, at an  
 9 unprecedented rate over the last decade. Today, even larger, younger coal plants are  
 10 struggling to survive the economic competition from cleaner, cheaper energy sources.<sup>9</sup>

11 **Q. Has the wave of coal plant retirements you describe reached Duke Energy and the**  
 12 **Carolinas?**

13 A. Yes. According to its 2018 IRP, since 2011, DEP has retired approximately 1,700 MW of  
 14 older coal generation.<sup>10</sup> Likewise, Duke Energy Carolinas (DEC) has retired about 1,700  
 15 MW of older coal units as of 2015.<sup>11</sup>

16 DEP itself is further planning to retire the two Asheville coal units later this year. The  
 17 Asheville units are actually newer than all of the Roxboro units, and unlike DEP's other

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<sup>8</sup> State of North Carolina, Executive Order 80 (Oct. 29, 2018), *available at* <https://governor.nc.gov/documents/executive-order-no-80-north-carolinas-commitment-address-climate-change-and-transition>.

<sup>9</sup> See, for example, E&E News, April 27, 2017: "Big Young Power Plants are Closing. Is it a new trend?" Available at <https://www.eenews.net/stories/1060053677>.

<sup>10</sup> DEP, South Carolina Integrated Resource Plan (2018) 71, *available at* <http://www.energy.sc.gov/files/DEP%202018%20IRP.pdf>.

<sup>11</sup> Duke Energy Carolinas, South Carolina Integrated Resource Plan (2018) 73, *available at* [http://www.energy.sc.gov/files/2018%20DEC%20Annual%20Plan\\_SC\\_Final.pdf](http://www.energy.sc.gov/files/2018%20DEC%20Annual%20Plan_SC_Final.pdf).

1 retired coal plants, they have installed advanced pollution controls such as those found at  
 2 Mayo and Roxboro. Once the Asheville units are retired, Mayo and Roxboro will be  
 3 DEP's only two remaining coal plants. Due Energy Carolinas is required by court order  
 4 to retire its Allen Units 1-3 in December 2024.

5 **Q. Had the retirement of DEP coal plants since 2011 been anticipated in the 2010**  
 6 **depreciation study?**

7 A. No. As of 2010, DEP was still reporting an anticipated end-of-life for Asheville Unit 1 of  
 8 2031, and Asheville Unit 2 of 2033.

9 **Q. Why did DEP elect to retire the Asheville units in 2019, when they had previously**  
 10 **been expected to continue operating until 2031 and 2033, respectively?**

11 A. By agreeing to permanently cease operations at Asheville no later than January 31, 2020,  
 12 DEP was able to take advantage of a provision of the North Carolina Mountain Energy  
 13 Act, which exempted the plant from certain coal ash-related legal requirements, and  
 14 thereby avoid significant environmental compliance costs. As described in the North  
 15 Carolina Utilities Commission Final Order under Docket No. E-2, Sub 1089, "Retirement  
 16 of the coal units at the Asheville Plant in the time frame provided under the Mountain  
 17 Energy Act (January 31, 2020) will...allow the Company to avoid significant capital  
 18 investments in environmental controls required by CAMA (i.e., new dry fly ash and  
 19 bottom ash handling technology and storm water requirements)."<sup>12</sup> The order also notes  
 20 that "DEP cautioned the Commission that without the Mountain Energy Act that extends

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<sup>12</sup> In re Application of DEP for a Certificate of Public Convenience and Necessity, Order of the North Carolina Utilities Commission, Docket No. E-2, sub 1089 (Mar. 28, 2016), available at <https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=50df4b08-ae5f-41c9-a1bd-8c26685673c2>.

1 CAMA deadlines and without this Commission's approval of the CPCN for the Project,  
2 DEP will be required to invest hundreds of millions of dollars in new environmental  
3 controls at the Asheville coal plant."

4 **Q. Have you seen evidence that DEP's coal units are experiencing more challenging**  
5 **economic conditions?**

6 A. Yes. All four units at Roxboro and the Mayo plant have been operating at much lower  
7 capacity factors than they were around the time of the prior depreciation studies (2002  
8 and 2010). This trend reflects their increased difficulty competing with other generation  
9 sources and represents another reason why their long-term economic outlook is poor.

10 **Q. What is the meaning of the term "capacity factor," as applied to electric generating**  
11 **units?**

12 A. The capacity factor is the total generation produced by a unit over a certain period of time,  
13 often a month or a year, as a percentage of the generation it could have produced were it  
14 running at 100% of its capacity for the same period of time.

15 **Q. What are typical historical capacity factors for coal plants in the United States?**

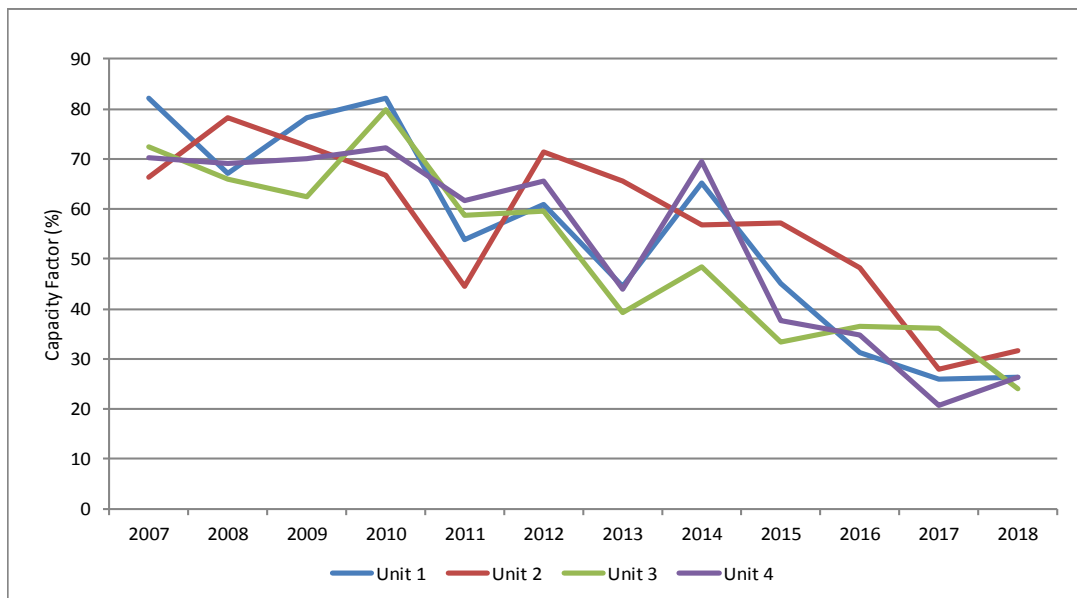
16 A. There is a great deal of variation depending on the plant type, efficiency, local system  
17 needs, and other factors. However, coal plants like those in DEP's fleet were designed to  
18 serve as baseload plants, which means they typically would have been expected to have  
19 capacity factors of 60% to 80%, or sometimes higher.

20 **Q. Are the coal units at Mayo and Roxboro currently operating as high capacity factor,**  
21 **baseload plants?**

22 A. No. As shown in Figures 1 and 2, for the last several years, all of the units at Roxboro  
23 and Mayo have been operating at capacity factors that are more typical of intermediate

units—units that cycle on and off or change their level of output in response to changes in load. While each of the Mayo and Roxboro units operated at a capacity factor between 60% and 80% through 2010, and closer to 60% in 2011 and 2012, they are now operating at capacity factors around 30% or below.

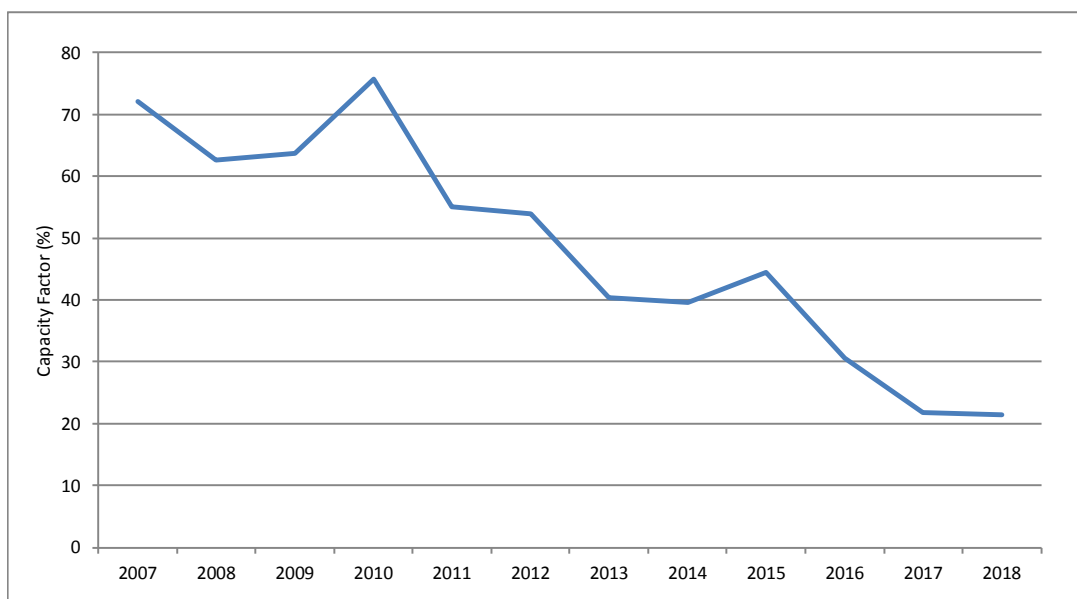
*Figure 1. Capacity Factors at Roxboro, 2007-2018*



Source: S&P Global Market Intelligence; SNL Energy Data; accessed February 11, 2019. (2018 represents capacity factor data through November 2018)

1

Figure 2. Capacity Factor at Mayo Unit 1, 2007-2018



2

3

4

Source: S&P Global Market Intelligence; SNL Energy Data; accessed February 11, 2019.  
(2018 represents capacity factor data through November 2018)

5

**Q. Why is the capacity factor relevant to the economic performance of the units?**

6

A. Most of the value of baseload plants lies in the energy they produce. These plants are very expensive to build and maintain, and this investment can only pay off for ratepayers if they produce as much energy as possible—i.e., if they have high capacity factors. As the output of the unit decreases, it becomes harder and harder to justify any additional expenditures to keep the plants operational and in compliance with all requirements. In this sense, low capacity factors are both a *symptom* of poor economics (because the plants can't compete with lower-cost resources) and a *cause* of diminishing economic viability.

12

1     **Q.     Have you found any indication that DEP no longer expects its coal resources to have**  
 2     **high capacity factors, or that it expects their capacity factors to continue to**  
 3     **decrease?**

4     A.     Yes. Up to and including the Company's 2014 IRP, DEP always listed its coal units as  
 5     "Base" resources. However, as of 2016, DEP began describing all the Mayo and Roxboro  
 6     units as "Intermediate," suggesting that DEP no longer considers base load operations to  
 7     be feasible for these resources.<sup>13</sup>

8     Further, in its confidential response to Sierra Club Data Request 1-19,

9     [CONFIDENTIAL] [REDACTED]  
 10    [REDACTED]  
 11    [REDACTED]  
 12    [REDACTED]  
 13    [REDACTED] [CONFIDENTIAL]

14    Finally, information provided in response to Sierra Club data requests suggests that

15    [CONFIDENTIAL] [REDACTED]  
 16    [REDACTED]  
 17    [REDACTED] [CONFIDENTIAL] In response to Sierra Club Data  
 18    Request 1-14 (attached as Exhibit 14), DEP provided the anticipated volume of bottom  
 19    and fly ash it expects to produce at each of its coal units from 2018 through 2040. (It is  
 20    not clear if the 2018 data are "actual" or "projected".) Because ash production is directly

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<sup>13</sup> DEP IRPs from 2010 through 2018 are available at <http://www.energy.sc.gov/utilities>.

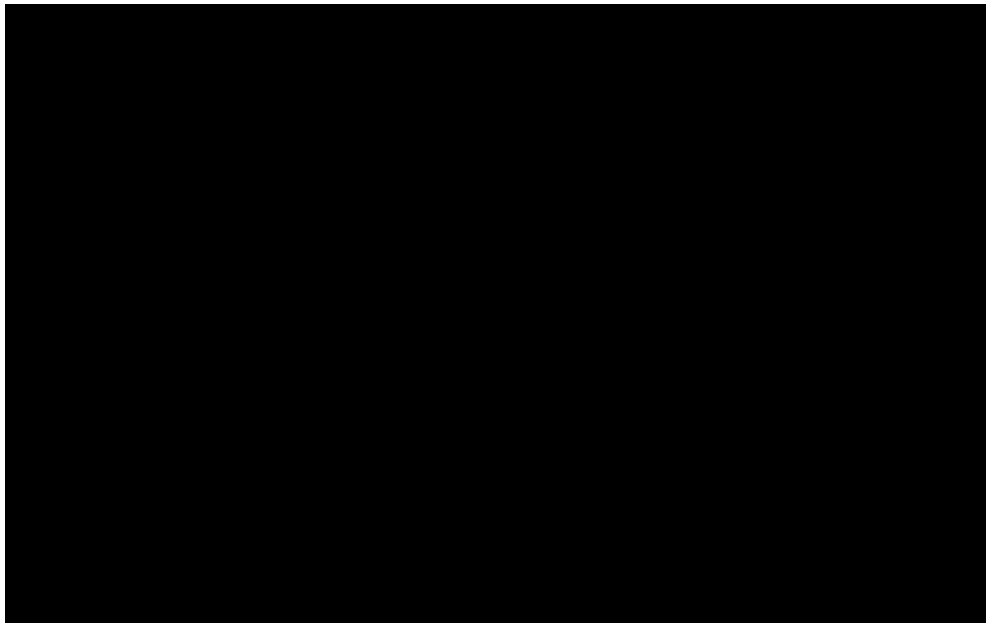
1 related to coal combustion, this serves as strong evidence of DEP's expectations for coal  
2 combustion at each unit during this period. As may be seen in Figure 4 through Figure 7,  
3 depicting fly ash production (the largest component), [CONFIDENTIAL] [REDACTED]

4 [REDACTED]

5 [REDACTED]

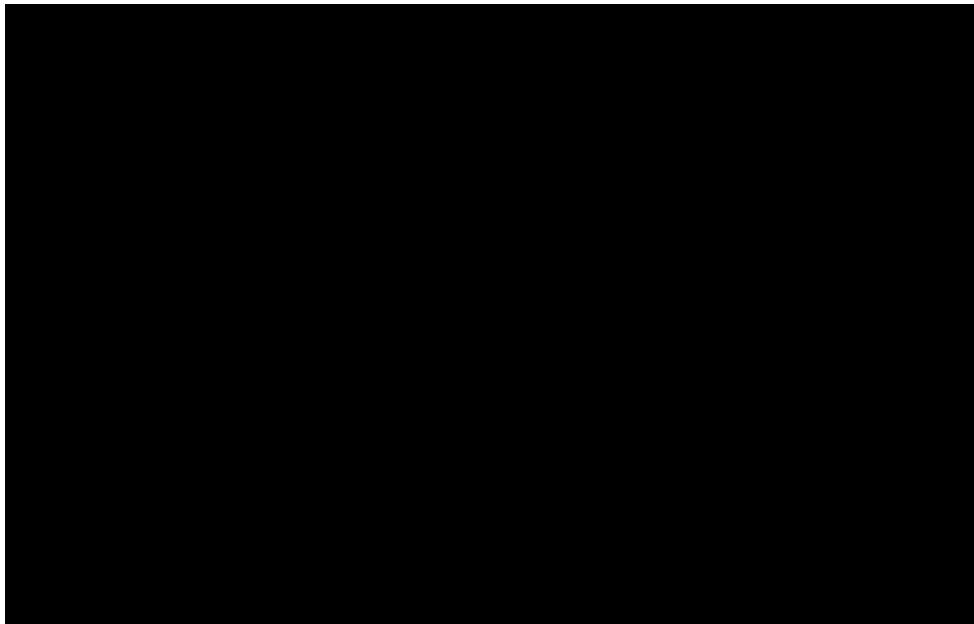
6 [CONFIDENTIAL]

7 [CONFIDENTIAL] *Figure 3. Projected fly ash production at Roxboro*



8  
9  
10

1 [CONFIDENTIAL] *Figure 4. Projected fly ash production at Mayo*



2  
3  
4 **IV. RECOMMENDATIONS**

5 **Q. What are your recommendations for the Commission in this proceeding?**

6 A. I recommend that the Commission reject DEP's request to recover its \$100 million  
7 investment in retrofits at the Roxboro plant because DEP has not demonstrated that such  
8 investment was economically preferable to the early retirement of that plant, when  
9 retirement would have allowed ratepayers to avoid both that investment and future capital  
10 costs for the plant.

11 In addition, I recommend that the Commission require DEP to complete a comprehensive  
12 economic and retirement analysis of each of its coal units. This analysis should identify  
13 and quantify the total costs of managing past and future CCR as well as the costs of all  
14 future capital investments necessary to continue operating the plants, including additional  
15 investments to manage coal ash and other environmental compliance requirements. This  
16 comprehensive analysis should include full consideration of non-fossil-generation

1 alternatives for meeting customer requirements, including transmission enhancements,  
2 renewable energy sources, energy efficiency, and storage. If the Commission otherwise  
3 concludes that DEP's request for recovery of coal ash remediation and cleanup costs in  
4 this proceeding to be reasonable and prudent, the Commission should condition its  
5 approval on its review of the Company's filing this comprehensive analysis for  
6 Commission review. This will allow the Commission to consider whether DEP's coal ash  
7 remediation investments provide commensurate benefits to ratepayers in the full context  
8 of the past and future operations of DEP's coal units.

9 Once the costs, benefits, and customer risks associated with continued operation versus  
10 early retirement of the plants are fully evaluated, the Commission will be better  
11 positioned to assess the reasonableness and prudence of any proposed additional capital  
12 investments. Moreover, such evaluation will allow the Company to better plan for  
13 transitioning to a cleaner energy mix, while minimizing the impact on ratepayers.

14 **Q. Does this conclude your direct testimony?**

15 **A.** Yes.